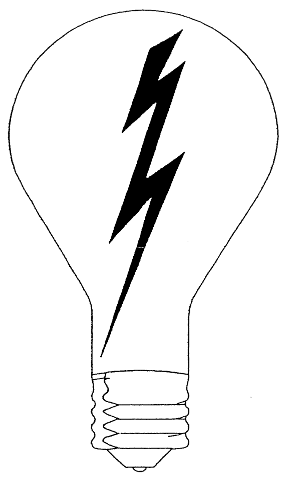
YEAR ENDING 2004

ANNUAL REPORT
OF

Black Hills Corporation

ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

Electric Annual Report

Table of Contents

continued on next page

Electric Annual Report

Instructions

General

1. A Microsoft EXCEL 2000 workbook of the annual report is being provided on computer disk for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1". By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell.

2. The workbook contains input sections that are unprotected, and non-input sections that are protected. Cell protection can be disabled or enabled through "TOOLS – PROTECTION – UNPROTECT SHEET" on your toolbar. Formulas and checks are built into most of the templates.

3. Use of the disk is optional. The disk and the report cover shall be returned when the report is filed. There are macros built into the workbook to assist you with the report. An explanation of the macros is on the "Control" worksheet at the front of the workbook. The explanations start at cell A1.

4. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed. **Please submit one unbound copy of the annual report along with the regular number of annual reports that you submit**. This aids in scanning the report so that it may be published on our web site. The orientation and margins are set up on each individual worksheet and should print on one page. If you elect not to use the disk, please format your reports to fit on one 8.5'' by 11'' page with the left binding edge (top if landscaped) set at .85'', the right edge (bottom if landscaped) set at .4'', and the remaining two margins at .5''. You may select specific schedules to print – See the worksheet "CONTROL".

5. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

6. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

7. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

8. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.

9. All companies owned by another company shall attach a corporate structure chart of the holding company.

10. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

11. The following schedules shall be filled out with information on a total company basis:

    Schedules 1 through 5
    Schedules 6 and 7
    Schedule 14
    Schedule 17 and 18
    Schedules 23 through 26
    Schedules 33 and 34

    All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

    Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

12. FERC Form-1 sheets may not be substituted in lieu of completing annual report schedules.

13. Common sense must be used when filling out all schedules.

Specific Instructions

Schedules 6 and 7

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 101 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

Schedules 8, 18, and 23

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

Schedule 12

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

Schedule 14

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form using FASB 87 and 132 guidelines.

3. Interest rate percentages shall be listed to two decimal places.

Schedule 15

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.

2. Schedule 15 shall be filled out using FASB 106 and 132 guidelines.

Schedule 16

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

Schedule 17

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).
2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

Schedule 24

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

Schedule 26

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

Schedule 27

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

3. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

Schedule 28

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

Schedule 31

1. This schedule shall be completed for the year following the reporting year.
2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

Schedule 32

1. Provide a written narrative detailing the sources and amounts of electric supply at the time of the annual peak.

Schedule 34

1. The following categories shall be used in the Type column: Thermal, Hydro, Nuclear, Solar, Wind, GeoThermal, Qualifying Facility (QF), Independent Power Producer (IPP), Off System Purchases, or Other. Spot market purchases shall be separately identified. Entries for the Other category shall be listed as separate line items and include a description.
   Note: For Off System Purchases, the Utility/Company whom the purchases are being made from shall be entered in the Plant Name column, the termination date of the purchased power contract shall be entered in the Location column.

2. Provide a written narrative of all outages exceeding one hour which occurred during the year. Explain the reason for the outage. If routine maintenance schedules are exceeded, explain the reason.

Schedule 35

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

IDENTIFICATION

Year: **2004**

1.	Legal Name of Respondent:	Black Hills Power, Inc.
2.	Name Under Which Respondent Does Business:	Black Hills Power, Inc.
3.	Date Utility Service First Offered in Montana	2/23/1968
4.	Address to send Correspondence Concerning Report:	Mark T. Thies 625 Ninth Street Rapid City, SD 57701
5.	Person Responsible for This Report:	Mark T. Thies Exec. V.P. & CFO
5a.	Telephone Number:	605-721-1700

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

1a. Name and address of the controlling organization or person:	Black Hills Corporation
1b. Means by which control was held:	Common Stock
1c. Percent Ownership:	100%

SCHEDULE 2

Board of Directors

Line No.	Name of Director and Address (City, State) (a)		Remuneration (b)
1	Bruce B. Brundage	Larkspur, CO	56,500
2	Thomas J. Zeller	Rapid City, SD	60,500
3	Jack W. Eugster (e)	Excelsior, MN	25,000
4	John R. Howard	Rapid City, SD	73,500
5	Everett E. Hoyt(a) (d)	Rapid City, SD	
6	Kay S. Jorgensen	Spearfish, SD	56,200
7	Daniel P. Landguth(a)	Rapid City, SD	
8	David C. Ebertz	Gillette, WY	52,000
9	David S. Maney(b)	Lakewood, CO	7,500
10	Richard Korpan	Evergreen, CO	52,500
11	David R. Emery(a) (c)	Rapid City, SD	
12	Stephen D. Newlin(c)	Medina, MN	36,000
13			
14			
15	(a) Officers of the Company -		
16	Not compensated as Directors		
17			
18	(b) Resigned from the Board of Directors January 9, 2004.		
19			
20	(c) Elected to the Board of Directors January 9, 2004		
21			
22	(d) Resgined from the Board of Directors May 26, 2004		
23			
24	(e) Elected to the Board of Directors May 26, 2004		
25			
26			
27			

BLACK HILLS CORPORATION ORGANIZATIONAL CHART

March 23, 2005

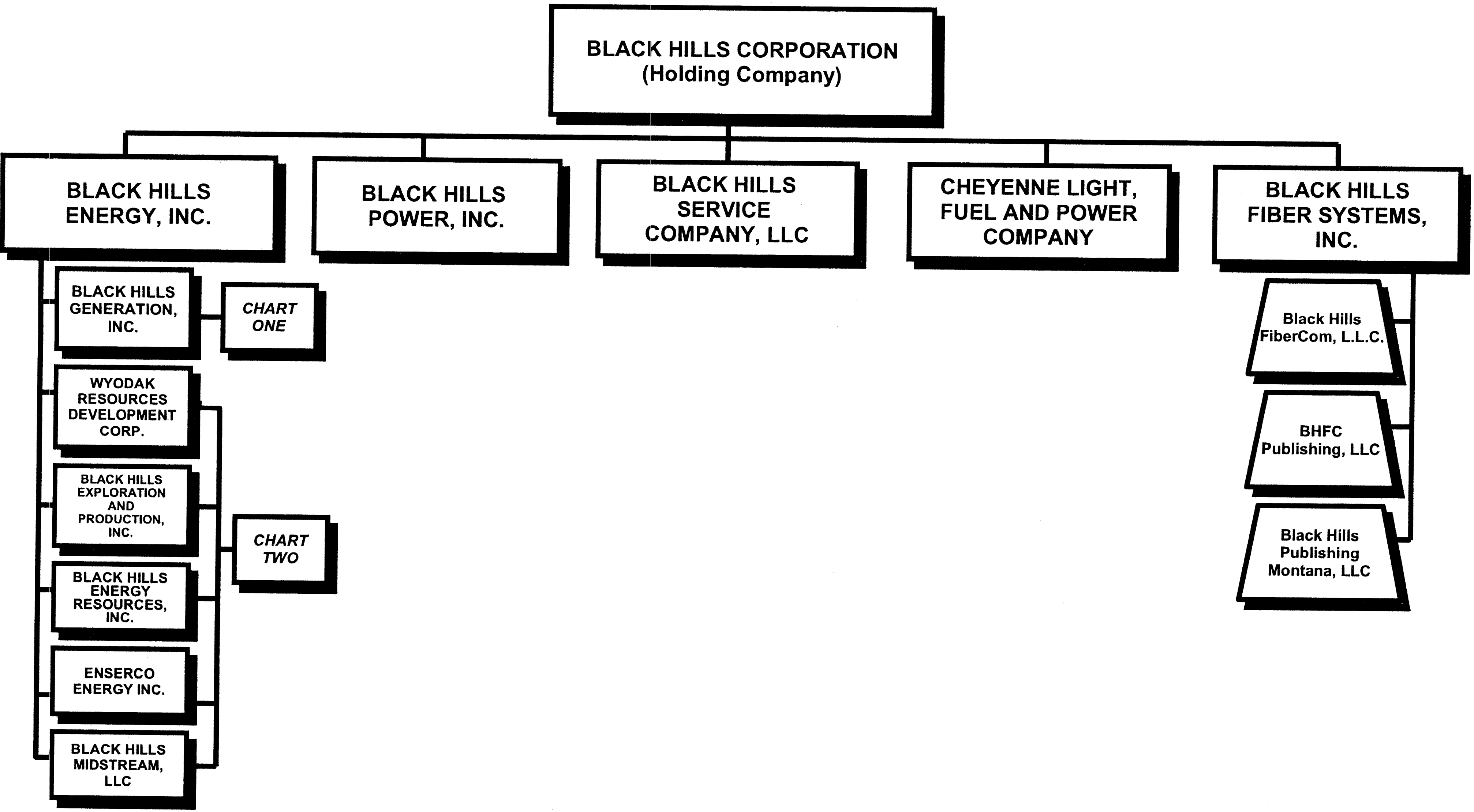


Chart One

March 3, 2005

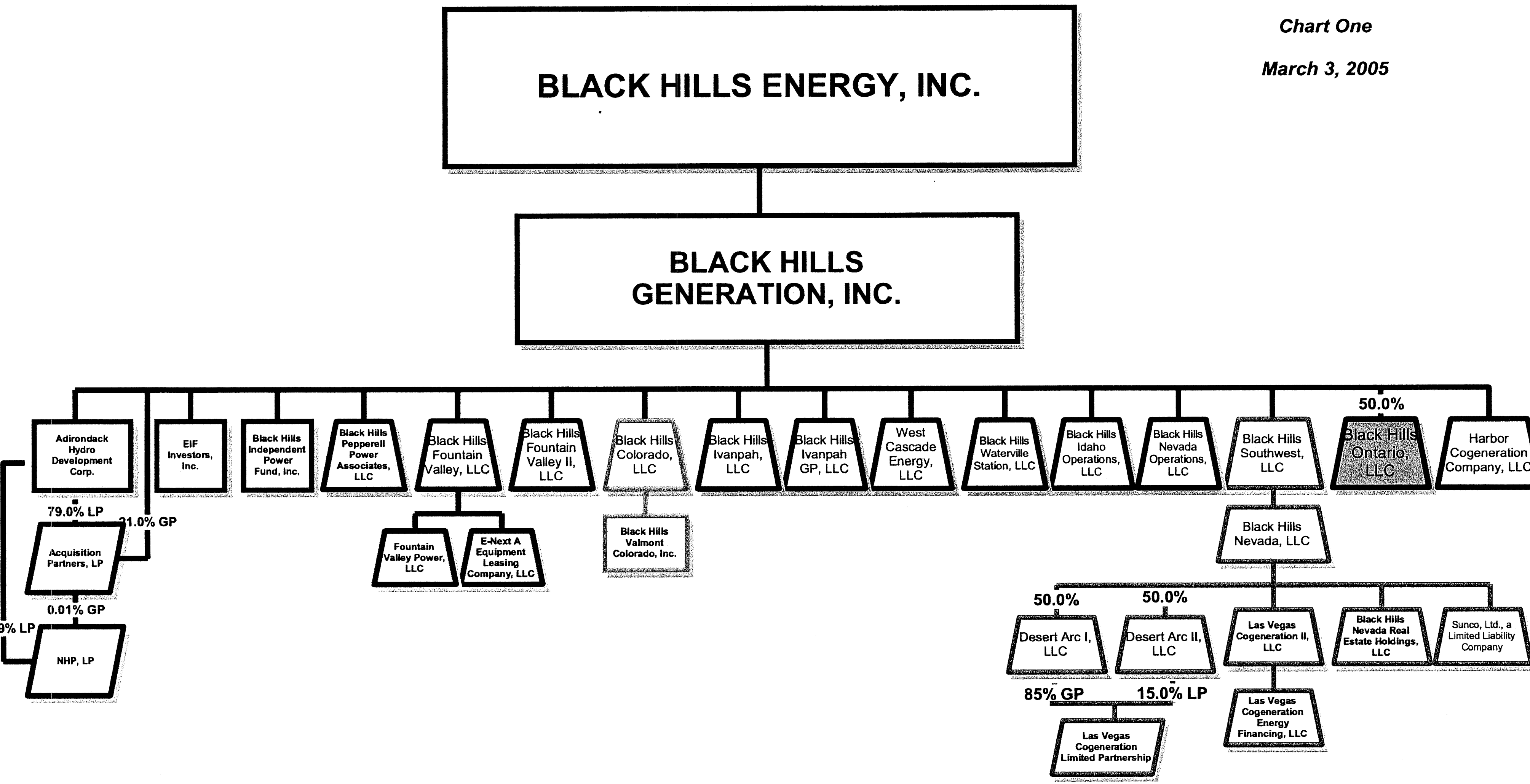
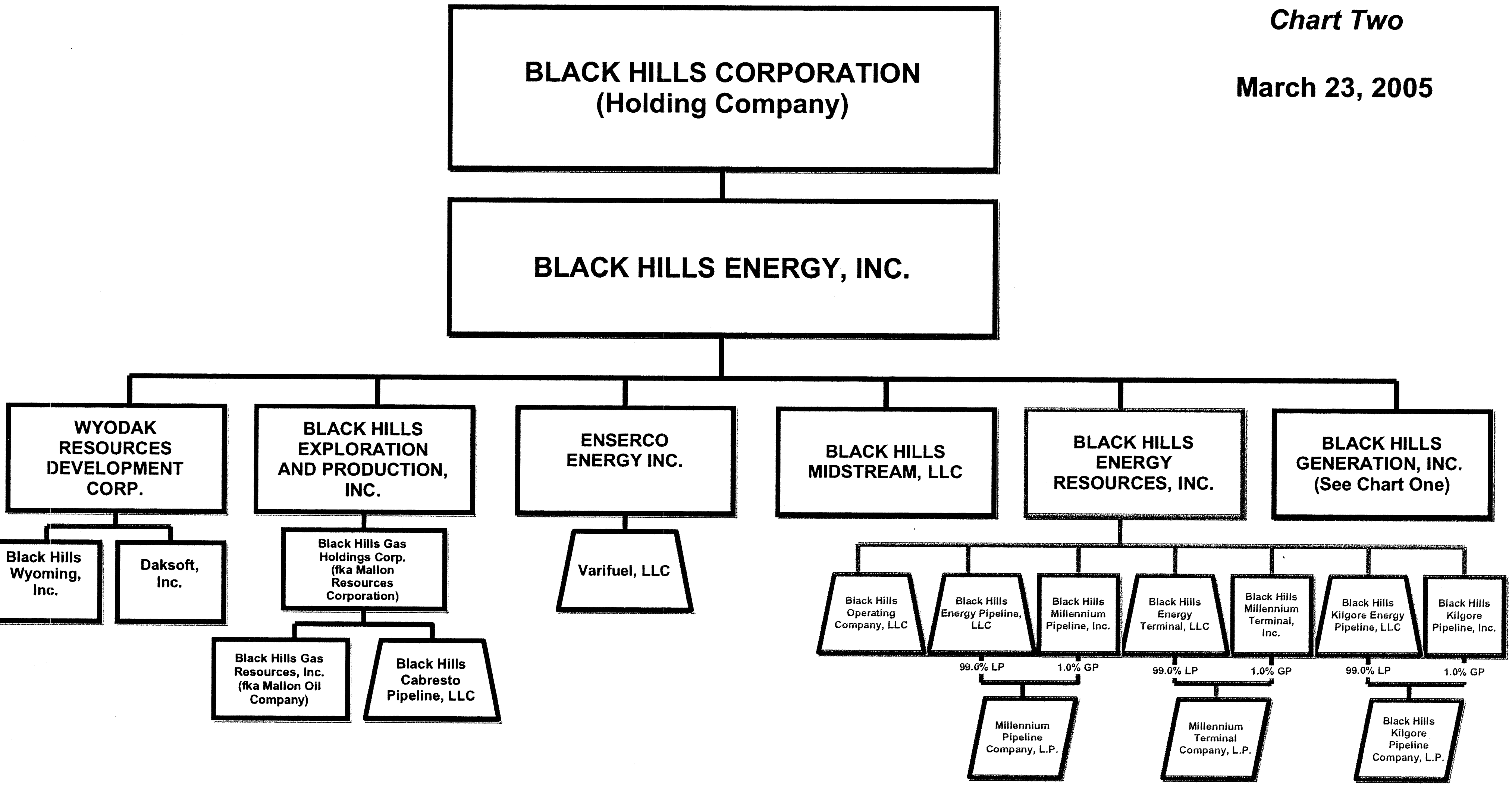


Chart Two

March 23, 2005



Officers

Year: 2004

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	Chairman of the Board		Daniel P. Landguth
2			
3	Vice Chairman		Everett E. Hoyt
4			
5	Chief Executive Officer		David R. Emery
6			
7	President and Chief Operating Officer		Linden R. Evans
8			
9	Executive Vice President, CFO,		Mark T. Thies
10	Assistant Treasurer and Assistant Secretary		
11			
12	Sr. Vice President - Corporate Administration		James M. Mattern
13	and Compliance		
14			
15	Sr. Vice President - General Counsel and		Steven J. Helmers
16	Assistant Secretary		
17			
18	Sr. Vice President and Chief Risk Officer		Russell L. Cohen
19			
20	Vice President Governance and		Roxann R. Basham
21	Corporate Secretary		
22			
23	Vice President and Treasurer		Garner Anderson
24			
25	Vice President - Corporate Affairs		Kyle D. White
26			
27	Vice President - Operations		Stuart Wevik
28			
29	Sr. Vice President - Strategic Planning and		Maurice T. Klefeker
30	Development		
31			
32	Vice President - Power Delivery		Mark L. Lux
33			
34	Vice President and Corporate Controller		David S. Smith
35			
36	Vice President and Corporate Controller		Perry Krush
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			

CORPORATE STRUCTURE

Year: 2004

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1	Black Hills Power, Inc.	Electric Utility	19,208,760	100.00%
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL**		19,208,760	100.00%

Company Name: Black Hills Power, Inc. **SCHEDULE 5**

CORPORATE ALLOCATIONS

Year: 2004

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Not Significant to Montana Operations					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2004

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1	Wyodak Resources	Coal sales to Utility	Fair Market Value (Based on	9,572,977	29.95%	81,370
2	Development Corp.		similar arms-length transactions)			
3						
4	Enserco Energy, Inc.	Gas sales to Utility	Fair Market Value (Based on	562,814	0.02%	4,784
5			similar arms-length transactions)			
6						
7	Black Hills FiberCom LLC	Telephone service	Fair Market Value (Based on	108,744	0.30%	688
8			similar arms-length transactions)			
9						
10	Black Hills FiberCom LLC	Miscellaneous	Fair Market Value (Based on	128,621	0.35%	
11			similar arms-length transactions)			
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL**			10,373,156		86,842

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1	Wyodak Resources					
2	Development corp.	Electricity	Wyoming Industrial Rate	720,770	100.00%	
3						
4	FiberCom LLC	Electricity	South Dakota Commercial Rate	356,152	100.00%	
5						
6	Black Hills Wyoming	Transmission Service	Point-to-Point			
7			Open Access Transmission Tariff	554,156	100.00%	
8						
9	Black Hills Wyoming	Non-firm energy sales	Fair Market Value (Based on			
10			similar arms-length transactions)	692,868	100.00%	
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL**			2,323,946		

MONTANA UTILITY INCOME STATEMENT*

Year: 2004

	Account Number & Title		Last Year	This Year	% Change
1	400	Operating Revenues	171,018,600	173,744,544	1.59%
2					
3		Operating Expenses			
4	401	Operation Expenses	84,733,264	94,395,337	11.40%
5	402	Maintenance Expense	8,024,770	8,773,623	9.33%
6	403	Depreciation Expense	18,847,762	18,721,971	-0.67%
7	404-405	Amortization of Electric Plant			
8	406	Amort. of Plant Acquisition Adjustments	151,404	151,404	
9	407	Amort. of Property Losses, Unrecovered Plant			
10		& Regulatory Study Costs			
11	408.1	Taxes Other Than Income Taxes	7,929,700	7,794,661	-1.70%
12	409.1	Income Taxes - Federal	3,553,955	5,731,341	61.27%
13		- Other			
14	410.1	Provision for Deferred Income Taxes	9,139,885	5,188,756	-43.23%
15	411.1	(Less) Provision for Def. Inc. Taxes - Cr.	(749,556)	(1,128,557)	-50.56%
16	411.4	Investment Tax Credit Adjustments	(318,304)	(279,115)	12.31%
17	411.6	(Less) Gains from Disposition of Utility Plant			
18	411.7	Losses from Disposition of Utility Plant			
19					
20		**TOTAL Utility Operating Expenses**	131,312,880	139,349,421	6.12%
21		**NET UTILITY OPERATING INCOME**	39,705,720	34,395,123	-13.37%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title		Last Year	This Year	% Change
1		Sales of Electricity			
2	440	Residential	5,020.00	5,484.00	9.24%
3	442	Commercial & Industrial - Small	16,681.00	13,972.00	-16.24%
4		Commercial & Industrial - Large	637,833.00	758,705.00	18.95%
5	444	Public Street & Highway Lighting			
6	445	Other Sales to Public Authorities			
7	446	Sales to Railroads & Railways			
8	448	Interdepartmental Sales			
9					
10		**TOTAL Sales to Ultimate Consumers**	659,534.00	778,161.00	17.99%
11	447	Sales for Resale			
12					
13		**TOTAL Sales of Electricity**	659,534.00	778,161.00	17.99%
14	449.1	(Less) Provision for Rate Refunds			
15					
16		**TOTAL Revenue Net of Provision for Refunds**	659,534.00	778,161.00	17.99%
17		Other Operating Revenues			
18	450	Forfeited Discounts & Late Payment Revenues	445.00	345.00	-22.47%
19	451	Miscellaneous Service Revenues			
20	453	Sales of Water & Water Power			
21	454	Rent From Electric Property			
22	455	Interdepartmental Rents			
23	456	Other Electric Revenues			
24					
25		**TOTAL Other Operating Revenues**	445.00	345.00	-22.47%
26		**Total Electric Operating Revenues**	659,979.00	778,506.00	17.96%

* Total Company Income Statement

Company Name: Black Hills Power, Inc. **SCHEDULE 8A**

Notes to Financial Statements Year: 2004

See Attached

(1) BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business Description

Black Hills Power, Inc. (the Company) is an electric utility serving customers in South Dakota, Wyoming and Montana. The Company is a wholly owned subsidiary of the publicly traded Black Hills Corporation, a registered public utility holding company, (the Parent).

Basis of Accounting

The financial statements have been prepared in accordance with the accounting requirements of the Uniform System of Accounts prescribed by the FERC. The principle differences from generally accepted accounting principles include the exclusion of current maturities of long term debt from current liabilities, the requirement to report deferred tax assets and liabilities separately, rather than as a single amount, the recording of asset removal costs as accumulated depreciation rather than as a liability and the exclusion of comparative statements of retained earnings and cash flows.

Regulatory Accounting

The Company's regulated electric operations are subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC).

The Company's electric operations follow the provisions of the Financial Accounting Standards Board (FASB) of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), and its financial statements reflect the effects of the different ratemaking principles followed by the various jurisdictions regulating its electric operations. As a result of the Company's 1995 rate case settlement, a 50-year depreciable life for Neil Simpson II is used for financial reporting purposes. If the Company were not following SFAS 71, a 35 to 40 year life would be more appropriate, which would increase depreciation expense by approximately $0.6 - $1.1 million per year. If rate recovery of generation-related costs becomes unlikely or uncertain, due to competition or regulatory action, these accounting standards may no longer apply to the Company's regulated generation operations. In the event the Company determines that it no longer meets the criteria for following SFAS 71, the accounting impact to the Company would be an extraordinary non-cash charge to operations of an amount that could be material. Criteria that give rise to the discontinuance of SFAS 71 include increasing competition that could restrict the Company's ability to establish prices to recover specific costs and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. The Company periodically reviews these criteria to ensure the continuing application of SFAS 71 is appropriate.

Utility Plant

Utility plant is recorded at cost, which includes an allowance for funds used during construction (AFUDC) where applicable. The cost of utility plant retired, together with removal cost less salvage, is charged to accumulated depreciation. Repairs and maintenance of utility plant are charged to operations as incurred.

AFUDC represents the approximate composite cost of borrowed funds and a return on capital used to finance the construction expenditures and is capitalized as a component of electric property. AFUDC was calculated at an annual composite rate of 9.8 percent during 2004 and 2003.

Depreciation

Depreciation is computed on a straight-line method over the estimated useful lives of the related assets. Depreciation provisions were equivalent to annual composite rates of 3.0 percent in 2004 and 3.1 percent in 2003.

Impairment of Long-Lived Assets

The Company periodically evaluates whether events and circumstances have occurred which may affect the estimated useful life or the recoverability of the remaining balance of its long-lived assets. If such events or circumstances were to indicate that the carrying amount of these assets was not recoverable, the Company would estimate the future cash flows expected to result from the use of the assets and their eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) was less than the carrying amount of the long-lived assets, the Company would recognize an impairment loss. No impairment loss was recorded during 2004 or 2003.

Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Materials, Supplies and Fuel

Materials, supplies and fuel used for construction, operation and maintenance purposes are generally stated at cost on a weighted-average basis.

Deferred Financing Costs

Deferred financing costs are amortized using the effective interest method over the term of the related debt.

Revenue Recognition

Revenue is recognized when there is persuasive evidence of an arrangement with a fixed or determinable price, delivery has occurred or services have been rendered, and collectibility is reasonably assured.

Income Taxes

The Company uses the liability method in accounting for income taxes. Under the liability method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements.

Fuel and Purchased Power Adjustment Tariffs

The Company's Montana Retail Tariffs contain clauses that allow recovery of certain fuel and purchased power costs in excess of the level of such costs included in base rates. These cost adjustment tariffs are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. The adjustments are recognized as current assets or current liabilities until adjusted through future billings to customers. Sales to Montana account for less than 10 percent of the Company's total electric revenue.

The Company's South Dakota, Wyoming, Wholesale to Montana-Dakota Utilities Co., (a division of MDU Resources Group, Inc. (MDU)) and City of Gillette tariffs do not include an automatic fuel and purchased power adjustment tariff.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America and to conform with accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to allowance for uncollectible accounts receivable, long-lived asset values and useful lives, employee benefit plans and contingencies. Actual results could differ from those estimates.

Recently Adopted Accounting Pronouncements

<u>FSP 106-2</u>

In May 2004, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP 106-2), which provides guidance on the accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (2003 Medicare Act) for employers that sponsor postretirement healthcare plans that provide prescription drug benefits. If the Plan is deemed actuarially equivalent to the prescription drug benefit under the 2003 Medicare Act, the sponsor of the Plan could be eligible for a federal subsidy. FSP 106-2 supersedes FSP 106-1 that was issued in January 2004 under the same title. FSP 106-2 is effective for the first interim period beginning after June 15, 2004. The Company provides prescription drug benefits to certain eligible employees. The actuarial measurement of the accumulated postretirement benefit obligation and net periodic postretirement benefit cost does not include the effects of the 2003 Medicare Act as it is believed the Plan is not actuarially equivalent (see Note 7).

Supplemental Disclosure of Cash Flow Information

Cash paid during the year 2004 for interest was $17,351,000 and cash paid during the year 2004 for income taxes was $5,753,000.

The Company distributed a stock dividend to Black Hills Corporation, its Parent Company, in the amount of $46.5 million (See Note 11).

(2) CAPITAL STOCK

The Company is a wholly-owned subsidiary of Black Hills Corporation.

(3) LONG-TERM DEBT

Substantially all of the Company's property is subject to the lien of the indenture securing its first mortgage bonds. First mortgage bonds of the Company may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. Scheduled maturities are approximately $2.0 million a year for the years 2005 through 2009.

(4) FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of the Company's financial instruments.

Long-term Debt

The fair value of the Company's long-term debt is estimated based on quoted market rates for utility debt instruments having similar maturities and similar debt ratings. The Company's outstanding first mortgage bonds are either currently not callable or are subject to make-whole provisions which would eliminate any economic benefits for the Company to call and refinance the first mortgage bonds.

The estimated fair values of the Company's financial instruments at December 31, are as follows (in thousands):

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 159,206	$ 190,273	$ 212,042	$ 238,331

(5) JOINTLY OWNED FACILITIES

The Company owns a 20 percent interest and PacifiCorp owns an 80 percent interest in the Wyodak Plant (Plant), a 362 megawatt coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp is the operator of the Plant.

The Company receives 20 percent of the Plant's capacity and is committed to pay 20 percent of its additions, replacements and operating and maintenance expenses. As of December 31, 2004, the Company's investment in the Plant included $73.4 million in electric plant and $34.5 million in accumulated depreciation, and is included in the corresponding captions in the accompanying Consolidated Balance Sheets. The Company's share of direct expenses of the Plant was $6.0 million and $5.8 million for the years ended December 31, 2004 and 2003, respectively, and is included in the corresponding categories of operating expenses in the accompanying Statements of Income.

The Company also owns a 35 percent interest and Basin Electric Power Cooperative owns a 65 percent interest in the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie placed into service in the fourth quarter of 2003. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the Western Electricity Coordinating Council (WECC) region and the Mid-Continent Area Power Pool, or "MAPP" region. The total transfer capacity of the tie is 400 megawatts – 200 megawatts West to East and 200 megawatts from East to West. The Company is committed to pay 35 percent of the additions, replacements and operating and maintenance expenses. For the twelve months ended December 31, 2004, the Company's share of direct expenses was $0.1 million. As of December 31, 2004, the Company's investment in the transmission tie was $19.7 million.

(6) COMMITMENTS AND CONTINGENCIES

Power Purchase and Transmission Services Agreement - PacifiCorp

In 1983, the Company entered into a 40 year power purchase agreement with PacifiCorp providing for the purchase by the Company of 75 megawatts of electric capacity and energy from PacifiCorp's system. An amended agreement signed in October 1997 reduces the contract capacity by 25 megawatts (5 megawatts per year starting in 2000). The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants. Costs incurred under this agreement were $10.0 million in 2004 and $10.8 million in 2003.

In addition, the Company has a firm network transmission agreement for 36 MWs of capacity with PacifiCorp that expires on December 31, 2006. Annual costs are approximately $0.9 million per year. The Company uses this agreement to serve the Sheridan, Wyoming electric service territory under the contract with Montana-Dakota Utilities Company.

The Company also has a firm point-to-point transmission service agreement with PacifiCorp that expires on December 31, 2023. The agreement provides that the following amounts of capacity and energy be transmitted: 32 megawatts in 2001, 27 megawatts in 2002, 22 megawatts in 2003, 17 megawatts in 2004-2006 and 50 megawatts in 2007-2023. Costs incurred under this agreement were $0.4 million in 2004 and $0.5 million in 2003.

Long-Term Power Sales Agreements

- The Company has a ten-year power sales contract with the Municipal Energy Agency of Nebraska (MEAN) for 20 megawatts of contingent capacity from the Neil Simpson Unit #2 plant. The contract commenced in February 2003.

- The Company has a contract with Montana-Dakota Utilities Company, expiring January 1, 2007, for the sale of up to 55 megawatts of energy and capacity to service the Sheridan, Wyoming electric service territory. The Company also has a contract with the City of Gillette, Wyoming, expiring in 2012, to provide the city's first 23 megawatts of capacity and energy. Both contracts are integrated into our control area and are treated as firm native load.

Legal Proceedings

Forest Fire Claims

In September 2001, a fire occurred in the southwestern Black Hills, now known as the "Hell Canyon Fire." It is alleged that the fire occurred when a high voltage electrical span maintained by the Company, broke, and electrical arcing from the severed line ignited dry grass. The fire burned approximately 10,000 acres of land owned by the Black Hills National Forest, the Oglala Sioux Tribe, and other private landowners. The State of South Dakota initiated litigation against the Company, in the Seventh Judicial Circuit Court, Fall River County, South Dakota, on or about January 31, 2003. The Complaint seeks recovery of damages for alleged fire suppression and rehabilitation costs. A claim for treble damages is asserted with respect to the claim for injury to timber. A substantially similar suit was filed against the Company by the United States Forest Service, on June 30, 2003, in the United States District Court for the District of South Dakota, Western Division. The State subsequently joined its claim in the federal action. The State claims damages in the amount of approximately $0.8 million for fire suppression and rehabilitation costs. The United States Government's claim for fire suppression and related costs has been submitted at approximately $1.3 million. The Company continues to investigate the cause and origin of the fire, and the damage claims. A trial date has been set for early 2005. The Company has denied all claims and will vigorously defend this matter, the timing or outcome of which is uncertain.

On June 29, 2002, a forest fire began near Deadwood, South Dakota, now known as the "Grizzly Gulch Fire." Before being contained more than eight days later, the fire consumed over 10,000 acres of public and private land, mostly consisting of rugged forested areas. The fire destroyed approximately 7 homes, and 15 outbuildings. There were no reported personal injuries. In addition, the fire burned to the edge of the City of Deadwood, forcing the evacuation of the City of Deadwood, and the adjacent City of Lead, South Dakota. These communities are active in the tourist and gaming industries. Individuals were ordered to leave their homes, and businesses were closed for a short period of time. On July 16, 2002, the State of South Dakota announced the results of its investigation of the cause and origin of the fire. The State asserted that the fire was caused by tree encroachment into and contact with a transmission line owned and maintained by the Company.

On September 6, 2002, the State of South Dakota commenced litigation against the Company, in the Seventh Judicial Circuit Court, Pennington County, South Dakota. The Complaint seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A claim for treble damages was asserted with respect to the claim for injury to timber.

On March 3, 2003, the United States of America filed a similar suit against the Company, in the United States District Court, District of South Dakota, Western Division. The federal government's Complaint likewise seeks recovery of damages for alleged injury to timber, fire suppression and rehabilitation costs. A similar claim for treble damages is asserted with respect to the claim for injury to timber. In April 2003, the State of South Dakota intervened in the federal action. Accordingly, the state court litigation has been stayed, and all governmental claims will be tried in U.S. District Court.

The state and federal government claim approximately $5.3 million for suppression costs, $1.2 million for rehabilitation costs, and $0.6 million for timber loss. Additional claims could be asserted for alleged loss of habitat and aesthetics or for assistance to private landowners.

The Company is completing its own investigation of the fire cause and origin. The Company's investigation is continuing, but based upon information currently available, the Company filed its Answer to the Complaints of both the State and the United States government, denying all claims, and asserting that the fire was caused by an independent intervening cause, or an act of God. The Company expects to vigorously defend all claims brought by governmental or private parties.

During the period of April 2003 through September 2004, various private civil actions were filed against the Company, asserting that the Grizzly Gulch Fire caused damage to the parties' real property. These actions were filed in the Fourth Judicial Circuit Court, Lawrence County, South Dakota. The Complaints seek recovery on the same theories asserted in the governmental Complaints, but most of the Complaints specify no amount for damage claims. The Company will vigorously defend these matters as well.

Additional claims could be made for individual and business losses relating to injury to personal and real property, and lost income.

Although we cannot predict the outcome or the viability of potential claims with respect to either fire, based on the information available, management believes that any such claims, if determined adversely to the Company, will not have a material adverse effect on the Company's financial condition or results of operations.

PPM Energy, Inc. Demand for Arbitration

On January 2, 2004, PPM Energy, Inc. delivered a Demand for Arbitration to the Company. The demand alleges claims for breach of contract and requests a declaration of the parties' rights and responsibilities under an Exchange Agreement executed on or about April 3, 2001. Specifically, PPM Energy asserts that the Exchange Agreement obligates the Company to accept receipt and cause corresponding delivery of electric energy, and to grant access to transmission rights allegedly covered by the Agreement. PPM Energy requests an award of damages in an amount not less than $20.0 million. The Company filed its Response to Demand, including a counterclaim that seeks recovery of sums PPM has refused to pay pursuant to the Exchange Agreement. The Company denies all claims and will vigorously defend this matter, the timing and outcome of which is uncertain.

Ongoing Litigation

The Company is subject to various other legal proceedings, claims and litigation which arise in the ordinary course of operations. In the opinion of management, the amount of liability, if any, with respect to these actions would not materially affect the financial position or results of operations of the Company.

(7) EMPLOYEE BENEFIT PLANS

Defined Benefit Pension Plan

The Company has a noncontributory defined benefit pension plan (Plan) covering the employees of the Company. The benefits are based on years of service and compensation levels during the highest five consecutive years of the last ten years of service. The Company's funding policy is in accordance with the federal government's funding requirements. The Plan's assets are held in trust and consist primarily of equity securities. The Company uses a September 30 measurement date for the Plan.

Obligations and Funded Status

Change in benefit obligation:

	2004	2003
	(in thousands)	

Projected benefit obligation at beginning of year	$ 44,803	$ 38,141
Service cost	959	714
Interest cost	2,621	2,500
Actuarial (gain) loss	(182)	1,110
Discount rate change	—	4,239
Benefits paid	(2,025)	(1,972)
Taxable wage rate and cost of living rate change	—	71
Net increase	1,373	6,662
Projected benefit obligation at end of year	$ 46,176	$ 44,803

A reconciliation of the fair value of Plan assets (as of the September 30 measurement date) is as follows:

	2004	2003
	(in thousands)	
Beginning market value of plan assets	$ 37,115	$ 25,830
Benefits paid	(2,025)	(1,972)
Investment income	4,754	6,406
Employer contributions	—	6,851
Ending market value of plan assets	$ 39,844	$ 37,115

Funding information for the Plan is as follows:

	2004	2003
	(in thousands)	
Fair value of plan assets	$ 39,844	$ 37,115
Projected benefit obligation	(46,176)	(44,803)
Funded status	(6,332)	(7,688)
Unrecognized:		
Net loss	14,860	17,457
Prior service cost	922	1,088
Net amount recognized	$ 9,450	$ 10,857

Amounts recognized in statement of financial position consist of:

	2004	2003
	(in thousands)	
Net pension asset	$ 9,450	$ 10,857
Accumulated benefit obligation	$ 38,302	$ 36,577

The provisions of SFAS No. 87 "Employers' Accounting for Pensions" (SFAS 87) required the Company to record a net pension asset of $9.5 million and $10.9 million at December 31, 2004 and 2003, respectively and is included in the line item Other in Other assets on the accompanying Balance Sheets.

Components of Net Periodic Pension Expense

	2004	2003
Service cost	$ 959	$ 714
Interest cost	2,621	2,500
Expected return on assets	(3,420)	(2,473)
Amortization of prior service cost	166	165
Recognized net actuarial loss	1,080	1,105
Net pension (income) expense	$ 1,406	$ 2,011

Additional Information

	2004	2003
	(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ —	$11,061

Assumptions

Weighted-average assumptions used to determine benefit obligations:	2004	2003
Discount rate	6.00%	6.00%
Rate of increase in compensation levels	4.39%	5.00%
Weighted-average assumptions used to determine net periodic benefit cost for plan year:	2004	2003
Discount rate	6.00%	6.75%
Expected long-term rate of return on assets*	9.50%	10.00%
Rate of increase in compensation levels	4.39%	5.00%

* The expected rate of return on plan assets was changed from 9.5 percent in 2004 to 9.0 percent for the calculation of the 2005 net periodic pension cost. This change is expected to increase pension costs in 2005 by approximately $0.2 million.

The Plan's expected long-term rate of return on assets assumption is based upon the weighted average expected long-term rate of returns for each individual asset class. The asset class weighting is determined using the target allocation for each asset class in the Plan portfolio. The expected long-term rate of return for each asset class is determined primarily from long-term historical returns for the asset class, with adjustments if it is anticipated that long-term future returns will not achieve historical results.

The expected long-term rate of return for equity investments was 10.0 percent and 10.5 percent for the 2004 and 2003 plan years, respectively. For determining the expected long-term rate of return for equity assets, the Company reviewed annual 20-, 30-, 40-, and 50-year returns on the S&P 500 Index, which were, at December 31, 2004, 13.2 percent, 13.7 percent, 10.4 percent and 10.9 percent respectively. Fund management fees were estimated to be 0.18 percent for S&P 500 Index assets and 0.45 percent for other assets. The expected long-term rate of return on fixed income investments was 6.0 percent; the return was based upon historical returns on intermediate-term treasury bonds of 6.3 percent from 1950 to 2002. The expected long-term rate of return on cash investments was estimated to be 4.0 percent; expected cash returns were estimated to be 2.0 percent below long-term returns on intermediate-term treasury bonds.

Plan Assets

Percentage of fair value of Plan assets at September 30:

	2004	2003
Domestic equity	59.7%	44.8%
Foreign equity	34.5	26.6
Fixed income	2.6	3.8
Cash	3.2	24.8[(a)]
Total	100.0%	100.0%

(a) Allocation includes $6.9 million cash contribution made to the plan on September 30, 2003.

The Plan's investment policy includes a target asset allocation as follows:

Asset Class	Target Allocation
US Stocks	60% (with a variance of no more or less than 10% of target).
Foreign Stocks	30% (with a variance of no more or less than 10% of target).
Fixed Income	5% (with a variance of no more than 10% or no less than 5% of target).
Cash	5% (with a variance of no more than 10% or no less than 5% of target).

The Plan's investment policy includes the investment objective that the achieved long-term rate of return meet or exceed the assumed actuarial rate. The policy strategy seeks to prudently invest in a diversified portfolio of predominately equity-based assets. The policy provides that the Plan will maintain a passive core US Stock portfolio based on the S&P 500 Index. Complementing this core will be investments in US and foreign equities through actively managed mutual funds.

The policy contains certain prohibitions on transactions in separately managed portfolios in which the Plan may invest, including prohibitions on short sales and the use of options or futures contracts. With regards to pooled funds, the policy requires the evaluation of the appropriateness of such funds for managing Plan assets if a fund engages in such transactions. The Plan has historically not invested in funds engaging in such transactions.

Cash Flows

The Company does not anticipate any employer contributions to the Plan in 2005.

Estimated Future Benefit Payments

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

2005	$ 2,165

2006	2,164
2007	2,201
2008	2,278
2009	2,375
2010-2014	13,568

Supplemental Nonqualified Defined Benefit Retirement Plans

The Company has various supplemental retirement plans for outside directors and key executives of the Company. The plans are nonqualified defined benefit plans. The Company uses a September 30 measurement date for the Plans.

Obligations and Funded Status

	2004	2003
	(in thousands)	
Change in benefit obligation:		
Projected benefit obligation at beginning of year	$ 1,886	$ 1,676
Service cost	—	6
Interest cost	110	109
Actuarial (gains) losses	(8)	197
Benefits paid	(102)	(102)
Net increase	—	210
Projected benefit obligation at end of year	$ 1,886	$ 1,886
Fair value of plan assets at end of year	$ —	$ —
Funded status	(1,886)	(1,886)
Unrecognized net loss	762	824
Unrecognized prior service cost	3	4
Contributions	36	25
Net amount recognized	$ (1,085)	$ (1,033)

	2004	2003
	(in thousands)	
Amounts recognized in statement of financial position consist of:		
Net pension liability	$ (1,650)	$ (1,613)
Intangible asset	3	4
Contributions	36	25
Accumulated other comprehensive loss	526	551
Net amount recognized	$ 1,085	$ (1,033)
Accumulated benefit obligation	$ 1,650	$ 1,615

The provisions of SFAS 87 required the Company to record an accrued pension liability of $1.7 million and $1.6 million at December 31, 2004 and 2003, and is included in Deferred credits and other liabilities, Other on the accompanying Balance Sheets.

Components of Net Periodic Benefit Cost

2004	2003

Service cost	$ —	$ 6
Interest cost	110	109
Amortization of prior service cost	1	(3)
Recognized net actuarial loss	53	42
Net periodic benefit cost	$ 164	$ 154

Additional Information

	2004	2003
	(in thousands)	
Pre-tax amount included in other comprehensive income (loss) arising from a change in the additional minimum pension liability	$ 25	$ (169)

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30	2004	2003
Discount rate	6.00%	6.00%
Rate of increase in compensation levels	5.00%	5.00%
Weighted-average assumptions used to determine net periodic benefit cost for plan year	2004	2003
Discount rate	6.00%	6.75%
Rate of increase in compensation levels	5.00%	5.00%

Plan Assets

The plan has no assets. The Company funds on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.1 million in 2005.

The following benefit payments, which reflect expected future service, are expected to be paid (in thousands):

Fiscal Year Ending	
2005	$ 90
2006	90
2007	90
2008	90
2009	90
2010-2014	451

Non-pension Defined Benefit Postretirement Plan

Employees who are participants in the Company's Postretirement Healthcare Plan and who retire from the Company on or after attaining age 55 after completing at least five years of service to the Company are entitled to postretirement healthcare benefits. These benefits are subject to premiums, deductibles, co-payment provisions and other limitations. The Company may amend or change the Plan periodically. The Company is not pre-funding its retiree medical plan. The Company uses a September 30 measurement date for the Plan.

These financial statements and this Note do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plan.

Obligation and Funded Status

	2004	2003
	(in thousands)	
Change in benefit obligation:		
Accumulated postretirement benefit obligation at beginning of year	$ 8,197	$ 6,547
Service cost	300	198
Interest cost	485	435
Plan participants' contributions	339	319
Benefits paid and actual expenses	(516)	(480)
Actuarial (gains) losses	(944)	1,178
Net increase	(336)	1,650
Accumulated postretirement benefit obligation at end of year	$ 7,861	$ 8,197
Fair value of plan assets at end of year	$ —	$ —
Funded status	(7,861)	(8,197)
Unrecognized net loss	1,842	2,930
Unrecognized prior service cost	(227)	(246)
Unrecognized transition obligation	934	1,050
Contributions	23	42
Net amount recognized	$ (5,289)	$ (4,421)

Amounts recognized in statement of financial position consist of:

	2004	2003
	(in thousands)	
Accrued postretirement liability	$ (5,289)	$ (4,421)

Components of Net Periodic Benefit Cost

	2004	2003
Service cost	$ 300	$ 198
Interest cost	486	435
Amortization of transition obligation	116	117
Amortization of prior service cost	(19)	(19)
Recognized net actuarial loss	144	78
Net periodic benefit cost	$ 1,027	$ 809

Assumptions

Weighted-average assumptions used to determine benefit obligations at September 30		
	2004	2003
Discount rate	6.00%	6.00%
Weighted-average assumptions used to determine net periodic benefit cost for plan year		
	2004	2003
Discount rate	6.00%	6.75%

The healthcare trend rate assumption for the 2003 fiscal year disclosure and 2004 fiscal year expense and disclosure is 12 percent for fiscal 2004 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2011. The health care cost trend rate assumption for the 2003 fiscal year expense was 11 percent for fiscal 2003 grading down 1 percent per year until a 5 percent ultimate trend rate is reached in fiscal year 2009.

A 1 percent increase in the healthcare cost trend assumption would increase the service and interest cost $0.2 million or 23 percent and the accumulated periodic postretirement benefit obligation $1.5 million or 19 percent. A 1 percent decrease would reduce the service and interest cost by $0.1 million or 17 percent and the accumulated periodic postretirement benefit obligation $1.2 million or 15 percent.

Plan Assets

The plan has no assets. The Company funds on a cash basis as benefits are paid.

Estimated Cash Flows

The estimated employer contribution is expected to be $0.2 million in 2005.

Estimated Future Benefit Payments

The following benefit payments, which reflect expected future service, are expected to be paid (in thousands):

Fiscal Year Ending

2005	$ 211
2006	236
2007	257
2008	273
2009	315
2010-2014	2,103

Defined Contribution Plan

The Company also sponsors a 401(k) savings plan for eligible employees. Participants elect to invest up to 20 percent of their eligible compensation on a pre-tax basis. The Company provides a matching contribution of 100 percent of the employee's tax-deferred contribution up to a maximum 3 percent of the employee's eligible compensation. Matching contributions vest at 20 percent per year and are fully vested when the participant has 5 years of service with the Company. The Company's matching contributions totaled approximately $0.4 million for 2004 and 2003.

(8) INCOME TAXES

Income tax expense from continuing operations for the years ended December 31 was (in thousands):

	2004	2003
Current	$ 5,731	$ 3,550
Deferred	3,781	8,072
	$ 9,512	$11,622

The temporary differences which gave rise to the net deferred tax liability were as follows (in thousands):

Years ended December 31,	2004	2003
Deferred tax assets, current:		
Valuation reserve	$ 319	$ 314
Employee benefits	2,984	2,623
Other	157	624
	3,460	3,561
Deferred tax liabilities, current:		
Prepaid expenses	155	—
Employee benefits	3,307	3,800
	3,462	3,800
Net deferred tax liability, current	$ 2	$ 239
Deferred tax assets, non-current:		
Regulatory asset	$ 1,025	$ 1,156
ITC	362	460
Items of other comprehensive income	184	193
Other	811	1,402
	2,382	3,211
Deferred tax liabilities, non-current:		
Accelerated depreciation and other plant related differences	66,275	63,615
AFUDC	2,712	2,808
Regulatory liability	1,460	1,512
Items of other comprehensive income	22	—
Other	1,146	909
	71,615	68,844
Net deferred tax liability, non-current	$ 69,233	$ 65,633
Net deferred tax liability	$ 69,235	$ 65,872

The following table reconciles the change in the net deferred income tax liability from December 31, 2003, to December 31, 2004, to deferred income tax expense (in thousands):

	2004
Increase in deferred income tax liability from the preceding table	$ 3,363
Deferred taxes associated with ITC	(508)
Deferred taxes associated with other comprehensive loss	(31)
Deferred taxes associated with 2003 federal income tax return true-up, primarily related to depreciation	957
Deferred income tax expense for the period	$ 3,781

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2004	2003
Federal statutory rate	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(1.5)	(1.3)
Research and development credit	—	(0.1)
Other	(0.4)	(1.1)
	33.1%	32.5%

(9) OTHER COMPREHENSIVE INCOME (LOSS)

The following tables display the related tax effects allocated to each component of Other Comprehensive Income (Loss) for the years ended December 31, (in thousands):

	2004		
	Pre-tax Amount	Tax Expense	Net-of-tax Amount
Minimum pension liability adjustment	$ 25	$ (9)	$ 16
Amortization of cash flow hedges settled and deferred in accumulated other comprehensive loss and reclassified into interest expense	64	(22)	42
Other comprehensive income	$ 89	$ (31)	$ 58

	2003		
	Pre-tax Amount	Tax Expense	Net-of-tax Amount
Minimum pension liability adjustment	$ 10,892	$(3,813)	$ 7,079
Net change in fair value of derivatives designated as cash flow hedges associated with discontinued operations	672	(269)	403
Amortization of cash flow hedges settled and deferred in accumulated other comprehensive loss and reclassified into interest expense	64	(22)	42
Other comprehensive income	$ 11,628	$(4,104)	$ 7,524

(10) RELATED-PARTY TRANSACTIONS

Receivables and Payables

The Company has accounts receivable balances related to transactions with other Black Hills Corporation subsidiaries. The balances were $0.9 million as of December 31, 2004 and 2003, respectively. The Company also has accounts payable balances related to transactions with other Black Hills Corporation subsidiaries. The balances were $0.3 million and $7.9 million as of December 31, 2004 and 2003, respectively.

The Company also has a line of credit with its Parent, Black Hills Corporation (the Parent), which is due on demand. Outstanding advances were $25.1 million at December 31, 2004. Interest expense paid on the note was $0.1 million for the year ended December 31, 2004. This note bears interest at 1.25 percent above the one-month average LIBOR rate (3.65 percent at December 31, 2004) and is payable monthly.

Other Balance and Transactions

The Company purchases coal from Wyodak Resources Development Corp., an indirect subsidiary of the Parent. The amount purchased during the years ended December 31, 2004 and 2003 was $9.6 million and $10.3 million.

In addition to the above transactions, in order to fuel its combustion turbine, the Company purchased natural gas from Enserco Energy, an indirect subsidiary of the Parent. The amount purchased during the years ended December 31, 2004 and 2003 was approximately $2.7 million and $6.1 million. These amounts are included in "Fuel and purchased power" on the Consolidated Statements of Income.

The Company also received revenues of approximately $1.0 million for the years ended December 31, 2004 and 2003, respectively, from Black Hills Wyoming, Inc., an indirect subsidiary of Black Hills Corporation, for the transmission of electricity.

(11) NON-CASH DIVIDEND AND DISCONTINUED OPERATIONS

During the quarter ended March 31, 2003, the Company distributed a non-cash dividend to its parent company, Black Hills Corporation (Parent). The dividend consisted of 10,000 common shares of Black Hills Generation, Inc., formerly known as Black Hills Energy Capital, Inc., (Generation), which represents 100 percent ownership of Generation. The Company therefore no longer operates in the independent power production business. As a result, the Company no longer has any subsidiaries and operates only in the electric utility business. The Company's investment in Generation at the time of the distribution was $46.5 million.

(12) SUBSEQUENT EVENTS

The Company has entered into an agreement with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., to provide wholesale power for the City of Sheridan, Wyoming. Under the agreement, the Company will provide all requirements up to 74 megawatts of power to Montana-Dakota from January 1, 2007 through January 1, 2017. Power requirements above 74 megawatts are negotiable under terms specified in the agreement. The contract is pending approval by the Wyoming Public Service Commission. An existing contract provides up to 55 megawatts and expires January 1, 2007.

MONTANA OPERATION & MAINTENANCE EXPENSES*

Year: 2004

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	1,074,077	1,002,044	-6.71%
6	501 Fuel	13,601,760	12,933,902	-4.91%
7	502 Steam Expenses	2,680,711	2,741,998	2.29%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	794,104	846,233	6.56%
11	506 Miscellaneous Steam Power Expenses	1,127,836	1,247,851	10.64%
12	507 Rents			
13				
14	TOTAL Operation - Steam	19,278,488	18,772,028	-2.63%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	198,873	283,067	42.34%
18	511 Maintenance of Structures	396,449	180,496	-54.47%
19	512 Maintenance of Boiler Plant	2,957,495	3,287,080	11.14%
20	513 Maintenance of Electric Plant	876,036	1,755,761	100.42%
21	514 Maintenance of Miscellaneous Steam Plant	546,764	576,246	5.39%
22				
23	TOTAL Maintenance - Steam	4,975,617	6,082,650	22.25%
24				
25	**TOTAL Steam Power Production Expenses**	24,254,105	24,854,678	2.48%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear		-	
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear		-	
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2004

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3	Operation			
4	535 Operation Supervision & Engineering			
5	536 Water for Power			
6	537 Hydraulic Expenses			
7	538 Electric Expenses			
8	539 Miscellaneous Hydraulic Power Gen. Expenses			
9	540 Rents			
10				
11	TOTAL Operation - Hydraulic		-	
12				
13	Maintenance			
14	541 Maintenance Supervision & Engineering			
15	542 Maintenance of Structures			
16	543 Maint. of Reservoirs, Dams & Waterways			
17	544 Maintenance of Electric Plant			
18	545 Maintenance of Miscellaneous Hydro Plant			
19				
20	TOTAL Maintenance - Hydraulic		-	
21				
22	**TOTAL Hydraulic Power Production Expenses**		-	
23				
24	Other Power Generation			
25	Operation			
26	546 Operation Supervision & Engineering	78,706	69,445	-11.77%
27	547 Fuel	7,361,231	2,214,762	-69.91%
28	548 Generation Expenses	334,850	304,141	-9.17%
29	549 Miscellaneous Other Power Gen. Expenses	45,525	22,838	-49.83%
30	550 Rents		9,223	#DIV/0!
31				
32	TOTAL Operation - Other	7,820,312	2,620,409	-66.49%
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering	49,496	96,556	95.08%
36	552 Maintenance of Structures	20,412	6,757	-66.90%
37	553 Maintenance of Generating & Electric Plant	868,315	844,714	-2.72%
38	554 Maintenance of Misc. Other Power Gen. Plant	10,260	9,136	-10.96%
39				
40	TOTAL Maintenance - Other	948,483	957,163	0.92%
41				
42	**TOTAL Other Power Production Expenses**	8,768,795	3,577,572	-59.20%
43				
44	Other Power Supply Expenses			
45	555 Purchased Power	34,520,289	46,329,877	34.21%
46	556 System Control & Load Dispatching			
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses	34,520,289	46,329,877	34.21%
50				
51	**TOTAL Power Production Expenses**	67,543,189	74,762,127	10.69%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2004

	Account Number & Title	Last Year	This Year	% Change
1	Transmission Expenses			
2	Operation			
3	560 Operation Supervision & Engineering	191,164	246,161	28.77%
4	561 Load Dispatching	707,498	677,982	-4.17%
5	562 Station Expenses	109,121	84,284	-22.76%
6	563 Overhead Line Expenses	25,236	49,442	95.92%
7	564 Underground Line Expenses			
8	565 Transmission of Electricity by Others	1,971,245	2,258,619	14.58%
9	566 Miscellaneous Transmission Expenses	196,171	161,709	-17.57%
10	567 Rents			
11				
12	TOTAL Operation - Transmission	3,200,435	3,478,197	8.68%
13	Maintenance			
14	568 Maintenance Supervision & Engineering	37,345	42,197	12.99%
15	569 Maintenance of Structures			
16	570 Maintenance of Station Equipment	71,081	87,515	23.12%
17	571 Maintenance of Overhead Lines	207,311	224,898	8.48%
18	572 Maintenance of Underground Lines			
19	573 Maintenance of Misc. Transmission Plant			
20				
21	TOTAL Maintenance - Transmission	315,737	354,610	12.31%
22				
23	**TOTAL Transmission Expenses**	3,516,172	3,832,807	9.01%
24				
25	Distribution Expenses			
26	Operation			
27	580 Operation Supervision & Engineering	545,718	544,632	-0.20%
28	581 Load Dispatching	96,212	117,473	22.10%
29	582 Station Expenses	283,982	281,800	-0.77%
30	583 Overhead Line Expenses	379,587	576,855	51.97%
31	584 Underground Line Expenses	203,236	212,075	4.35%
32	585 Street Lighting & Signal System Expenses	956	3,802	297.70%
33	586 Meter Expenses	500,598	454,789	-9.15%
34	587 Customer Installations Expenses	45,674	38,718	-15.23%
35	588 Miscellaneous Distribution Expenses	414,274	352,077	-15.01%
36	589 Rents	22,461	23,040	2.58%
37				
38	TOTAL Operation - Distribution	2,492,698	2,605,261	4.52%
39	Maintenance			
40	590 Maintenance Supervision & Engineering	21,387	22,733	6.29%
41	591 Maintenance of Structures			
42	592 Maintenance of Station Equipment	32,251	80,178	148.61%
43	593 Maintenance of Overhead Lines	1,199,937	763,814	-36.35%
44	594 Maintenance of Underground Lines	143,583	103,221	-28.11%
45	595 Maintenance of Line Transformers	14,458	10,637	-26.43%
46	596 Maintenance of Street Lighting, Signal Systems	101,449	101,301	-0.15%
47	597 Maintenance of Meters	49,400	48,058	-2.72%
48	598 Maintenance of Miscellaneous Dist. Plant	23,019	59,226	157.29%
49				
50	TOTAL Maintenance - Distribution	1,585,484	1,189,168	-25.00%
51				
52	**TOTAL Distribution Expenses**	4,078,182	3,794,429	-6.96%

Company Name: **Black Hills Power, Inc.**

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2004

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision	94,722	32,181	-66.03%
4	902 Meter Reading Expenses	826,649	407,334	-50.72%
5	903 Customer Records & Collection Expenses	1,682,667	909,031	-45.98%
6	904 Uncollectible Accounts Expenses	427,090	189,263	-55.69%
7	905 Miscellaneous Customer Accounts Expenses	934,079	515,837	-44.78%
8				
9	TOTAL Customer Accounts Expenses	3,965,207	2,053,646	-48.21%
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision	64,054	67,210	4.93%
14	908 Customer Assistance Expenses	804,563	779,870	-3.07%
15	909 Informational & Instructional Adv. Expenses	6,802	5,847	-14.04%
16	910 Miscellaneous Customer Service & Info. Exp.	43,237	76,826	77.69%
17				
18	TOTAL Customer Service & Info Expenses	918,656	929,753	1.21%
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision			
23	912 Demonstrating & Selling Expenses			
24	913 Advertising Expenses			
25	916 Miscellaneous Sales Expenses			
26				
27	TOTAL Sales Expenses		-	
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries	4,376,608	4,384,438	0.18%
32	921 Office Supplies & Expenses	315,616	2,581,089	717.79%
33	922 (Less) Administrative Expenses Transferred - Cr.	(16,005)	(57,051)	-256.46%
34	923 Outside Services Employed	2,982,675	5,034,383	68.79%
35	924 Property Insurance	1,002,680	850,133	-15.21%
36	925 Injuries & Damages	639,134	1,281,703	100.54%
37	926 Employee Pensions & Benefits	2,396,761	2,806,960	17.11%
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses	298,299	195,565	-34.44%
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses	177,765	121,741	-31.52%
42	930.2 Miscellaneous General Expenses	186,191	195,111	4.79%
43	931 Rents	177,455	212,094	19.52%
44				
45	TOTAL Operation - Admin. & General	12,537,179	17,606,166	40.43%
46	Maintenance			
47	935 Maintenance of General Plant	199,449	190,033	-4.72%
48				
49	**TOTAL Administrative & General Expenses**	12,736,628	17,796,199	39.72%
50				
51	**TOTAL Operation & Maintenance Expenses**	92,758,034	103,168,961	11.22%

*Total Company Operation and Maintenance Expense

MONTANA TAXES OTHER THAN INCOME

Year: 2004

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel			
5	Montana PSC	827	1,274	54.05%
6	Franchise Taxes			
7	Property Taxes	70,351	71,682	1.89%
8	Tribal Taxes			
9	Montana Wholesale Energy Tax	2,027	2,736	34.98%
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51	**TOTAL MT Taxes Other Than Income**	73,205	75,692	3.40%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES Year: 2004

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Amounts to Montana Are Not Significant				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
50	**TOTAL Payments for Services**				

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2004

	Description	Total Company	Montana	% Montana
1	NONE			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Contributions**			

Pension Costs

Year: 2004

1	Plan Name			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? _Project Unit Cost Method	IRS Code: 401(b)		
4	Annual Contribution by Employer: $0	Is the Plan Over Funded? No		
5				

	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	44,803,319	38,140,491	-14.87%
8	Service cost	958,523	713,597	-25.55%
9	Interest Cost	2,621,330	2,500,415	-4.61%
10	Plan participants' contributions			
11	Amendments			
12	Actuarial Gain	(182,135)	5,420,623	3076.16%
13	Acquisition			
14	Benefits paid	(2,024,767)	(1,971,807)	2.62%
15	Benefit obligation at end of year	46,176,270	44,803,319	-2.97%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	37,115,057	25,829,604	-30.41%
18	Actual return on plan assets	4,753,540	6,406,472	34.77%
19	Acquisition			
20	Employer contribution		6,850,788	#DIV/0!
21	Plan participants' contributions		-	
22	Benefits paid	(2,024,767)	(1,971,807)	2.62%
23	Fair value of plan assets at end of year	39,843,830	37,115,057	-6.85%
24	**Funded Status**	(6,332,440)	(7,688,262)	-21.41%
25	Unrecognized net actuarial loss	14,859,973	17,456,980	17.48%
26	Unrecognized prior service cost	922,428	1,087,888	17.94%
27	Prepaid (accrued) benefit cost	9,449,961	10,856,606	14.89%
28				
29	**Weighted-average Assumptions as of Year End**			
30	Discount rate	6.00%	6.75%	12.50%
31	Expected return on plan assets	9.50%	10.00%	5.26%
32	Rate of compensation increase	5.00%	5.00%	
33				
34	**Components of Net Periodic Benefit Costs**			
35	Service cost	958,523	713,597	-25.55%
36	Interest cost	2,621,330	2,500,415	-4.61%
37	Expected return on plan assets	(3,420,054)	(2,473,229)	27.68%
38	Amortization of prior service cost	165,460	165,462	0.00%
39	Recognized net actuarial loss	1,081,386	1,105,050	2.19%
40	Net periodic benefit cost	1,406,645	2,011,295	42.99%
41				
42	**Montana Intrastate Costs:**			
43	Pension Costs			
44	Pension Costs Capitalized			
45	Accumulated Pension Asset (Liability) at Year End			
46	**Number of Company Employees:**			
47	Covered by the Plan	836	811	-2.99%
48	Not Covered by the Plan	33	31	-6.06%
49	Active	487	479	-1.64%
50	Retired	169	159	-5.92%
51	Deferred Vested Terminated	147	142	-3.40%

Other Post Employment Benefits (OPEBS)

Year: 2004

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: ___________			
4	Order number: ____________			
5	Amount recovered through rates			
6	**Weighted-average Assumptions as of Year End**			
7	Discount rate	6.00%	6.75%	12.50%
8	Expected return on plan assets			
9	Medical Cost Inflation Rate	12.00%	12.00%	
10	Actuarial Cost Method	Projected Unit Cost	Projected Unit Cost	
11	Rate of compensation increase	5.00%	5.00%	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13				
14				
15	**Describe any Changes to the Benefit Plan:**			
16				
17	TOTAL COMPANY			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	4,420,606	3,764,185	(0)
20	Service cost	299,742	198,323	(0)
21	Interest Cost	485,520	435,106	(0)
22	Plan participants' contributions			-
23	Amendments			-
24	Actuarial Gain	241,723	175,482	(0)
25	Acquisition			-
26	Benefits paid	(157,982)	(152,490)	0
27	Benefit obligation at end of year	5,289,609	4,420,606	(0)
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	-		-
30	Actual return on plan assets			-
31	Acquisition			-
32	Employer contribution			-
33	Plan participants' contributions	-	-	-
34	Benefits paid	-	-	-
35	Fair value of plan assets at end of year	-	-	-
36	**Funded Status**	(5,289,609)	(3,764,185)	0
37	Unrecognized net actuarial loss			-
38	Unrecognized prior service cost			-
39	Prepaid (accrued) benefit cost	(5,289,609)	(3,764,185)	0
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	299,742	198,323	(0)
42	Interest cost	485,520	435,106	(0)
43	Expected return on plan assets		-	-
44	Amortization of prior service cost			-
45	Recognized net actuarial loss	241,723	175,482	(0)
46	Net periodic benefit cost	1,026,985	808,911	(0)
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA			-
49	Amount Funded through 401(h)			-
50	Amount Funded through Other ________________			-
51	**TOTAL**	-	-	-
52	Amount that was tax deductible - VEBA			-
53	Amount that was tax deductible - 401(h)			-
54	Amount that was tax deductible - Other ___________			-
55	TOTAL	-	-	-

Company Name: Black Hills Power, Inc. **SCHEDULE 15**

Other Post Employment Benefits (OPEBS) Continued

Year: 2004

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	689	683	-1%
3	Not Covered by the Plan			
4	Active	480	472	-2%
5	Retired	113	116	3%
6	Spouses/Dependants covered by the Plan	96	95	-1%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year	-	-	-
10	Service cost			-
11	Interest Cost			-
12	Plan participants' contributions			-
13	Amendments			-
14	Actuarial Gain			-
15	Acquisition			-
16	Benefits paid			-
17	Benefit obligation at end of year	-	-	-
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year	-	-	-
20	Actual return on plan assets			-
21	Acquisition			-
22	Employer contribution			-
23	Plan participants' contributions	-	-	-
24	Benefits paid	-	-	-
25	Fair value of plan assets at end of year	-	-	-
26	**Funded Status**	-	-	-
27	Unrecognized net actuarial loss			-
28	Unrecognized prior service cost			-
29	Prepaid (accrued) benefit cost	-	-	-
30	**Components of Net Periodic Benefit Costs**			
31	Service cost	-	-	-
32	Interest cost	-	-	-
33	Expected return on plan assets	-	-	-
34	Amortization of prior service cost			-
35	Recognized net actuarial loss			-
36	Net periodic benefit cost	-	-	-
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			-
39	Amount Funded through 401(h)			-
40	Amount Funded through other ________________			-
41	**TOTAL**	-	-	-
42	Amount that was tax deductible - VEBA			-
43	Amount that was tax deductible - 401(h)			-
44	Amount that was tax deductible - Other			-
45	TOTAL	-	-	-
46	**Montana Intrastate Costs:**			
47	Pension Costs			-
48	Pension Costs Capitalized			-
49	Accumulated Pension Asset (Liability) at Year End			-
50	**Number of Montana Employees:**			
51	Covered by the Plan			-
52	Not Covered by the Plan			-
53	Active			-
54	Retired			-
55	Spouses/Dependants covered by the Plan			

Company Name: **Black Hills Power, Inc.**

SCHEDULE 16

Year: 2004

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							

Company Name: Black Hills Power, Inc.

SCHEDULE 17

Year: 2004

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Daniel P. Landguth Chairman of the Board	537,160	110,789	770,307	1,418,256	1,348,198	5%
2	David R. Emery Chief Executive Officer	392,485	88,363	173,790	654,638	399,577	64%
3	Mark T. Thies Executive Vice President CFO, Assistant Treasurer, and Assistant Secretary	259,100	38,865	163,978	461,942	489,838	-6%
4	Steven J. Helmers Senior Vice President, General Counsel, and Assistant Secretary	240,000	31,500	142,573	414,073	340,964	21%
5	Russell L. Cohen Senior Vice President and Chief Risk Officer	234,000	35,100	61,561	330,661	406,999	-19%
6	Everett E. Hoyt (a) Vice Chairman	317,191	68,006	1,884,374	2,269,571	1,505,667	51%

(a) Individual was no longer serving as an executive officer at December 31, 2004

BALANCE SHEET

Year: 2004

	Account Number & Title		Last Year	This Year	% Change
1		**Assets and Other Debits**			
2	Utility Plant				
3	101	Electric Plant in Service	594,716,449	607,392,736	2%
4	101.1	Property Under Capital Leases			
5	102	Electric Plant Purchased or Sold			
6	104	Electric Plant Leased to Others			
7	105	Electric Plant Held for Future Use			
8	106	Completed Constr. Not Classified - Electric	30,922,544	28,441,912	-8%
9	107	Construction Work in Progress - Electric	3,059,757	4,065,626	33%
10	108	(Less) Accumulated Depreciation	(223,454,961)	(240,472,137)	-8%
11	111	(Less) Accumulated Amortization			
12	114	Electric Plant Acquisition Adjustments	4,870,308	4,870,308	
13	115	(Less) Accum. Amort. Elec. Acq. Adj.	(1,917,787)	(2,069,191)	-8%
14	120	Nuclear Fuel (Net)			
15		**TOTAL Utility Plant**	408,196,310	402,229,254	1%
16					
17	**Other Property & Investments**				
18	121	Nonutility Property	5,618	5,618	
19	122	(Less) Accum. Depr. & Amort. for Nonutil. Prop.	(3,956)	(3,956)	
20	123	Investments in Associated Companies			
21	123.1	Investments in Subsidiary Companies	-		
22	124	Other Investments	3,181,746	3,395,292	7%
23	125	Sinking Funds			
24		**TOTAL Other Property & Investments**	3,183,408	3,396,954	-6%
25					
26	**Current & Accrued Assets**				
27	131	Cash	1,048,254	3,410,024	225%
28	132-134	Special Deposits			
29	135	Working Funds	3,325	3,400	2%
30	136	Temporary Cash Investments		133,399	#DIV/0!
31	141	Notes Receivable			
32	142	Customer Accounts Receivable	11,633,325	13,447,835	16%
33	143	Other Accounts Receivable	1,292,948	1,264,005	-2%
34	144	(Less) Accum. Provision for Uncollectible Accts.	(898,380)	(911,537)	-1%
35	145	Notes Receivable - Associated Companies	37,709,836		-100%
36	146	Accounts Receivable - Associated Companies	907,793	890,550	-2%
37	151	Fuel Stock	1,580,687	2,210,658	40%
38	152	Fuel Stock Expenses Undistributed			
39	153	Residuals			
40	154	Plant Materials and Operating Supplies	7,984,775	9,302,453	17%
41	155	Merchandise			
42	156	Other Material & Supplies	(39)	(174)	-346%
43	157	Nuclear Materials Held for Sale			
44	163	Stores Expense Undistributed	(5,216)		100%
45	165	Prepayments	13,670,038	11,765,887	-14%
46	171	Interest & Dividends Receivable			
47	172	Rents Receivable			
48	173	Accrued Utility Revenues	4,679,848	4,383,846	-6%
49	174	Miscellaneous Current & Accrued Assets		29,838	-100%
50		**TOTAL Current & Accrued Assets**	79,607,194	45,930,184	73%

Company Name: Black Hills Power, Inc. **SCHEDULE 18**

BALANCE SHEET

Year: 2004

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Assets and Other Debits (cont.)**			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	2,092,634	1,567,729	33%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	183	Prelim. Survey & Investigation Charges	9	333,936	-100%
10	184	Clearing Accounts	304,716	312,330	-2%
11	185	Temporary Facilities			
12	186	Miscellaneous Deferred Debits	2,163,698	1,599,301	35%
13	187	Deferred Losses from Disposition of Util. Plant			
14	188	Research, Devel. & Demonstration Expend.			
15	189	Unamortized Loss on Reacquired Debt	246,861	3,064,215	-92%
16	190	Accumulated Deferred Income Taxes	10,478,780	10,015,830	5%
17		**TOTAL Deferred Debits**	15,286,698	16,893,341	-10%
18					
19		**TOTAL Assets & Other Debits**	506,273,610	468,449,733	8%
	Account Title		Last Year	This Year	% Change
20					
21		**Liabilities and Other Credits**			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	23,416,396	23,416,396	
26	202	Common Stock Subscribed			
27	204	Preferred Stock Issued			
28	205	Preferred Stock Subscribed			
29	207	Premium on Capital Stock	42,050,811	42,050,811	
30	211	Miscellaneous Paid-In Capital			
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	(2,501,882)	(2,501,882)	
33	215	Appropriated Retained Earnings			
34	216	Unappropriated Retained Earnings	114,097,956	109,306,716	4%
35	217	(Less) Reacquired Capital Stock			
36	219	Accumulated Other Comprehensive Income	(1,494,224)	(1,435,853)	
37		**TOTAL Proprietary Capital**	175,569,057	170,836,188	3%
38					
39	**Long Term Debt**				
40					
41	221	Bonds	184,230,000	137,275,000	-25%
42	222	(Less) Reacquired Bonds			
43	223	Advances from Associated Companies			
44	224	Other Long Term Debt	27,811,728	21,930,648	-21%
45	225	Unamortized Premium on Long Term Debt			
46	226	(Less) Unamort. Discount on L-Term Debt-Dr.			
47		**TOTAL Long Term Debt**	212,041,728	159,205,648	33%

BALANCE SHEET

Year: 2004

	Account Number & Title		This Year	This Year	% Change
1					
2	**Total Liabilities and Other Credits (cont.)**				
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages			
9	228.3	Accumulated Provision for Pensions & Benefits			
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12	**TOTAL Other Noncurrent Liabilities**			-	
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable			
17	232	Accounts Payable	6,441,811	7,102,073	10%
18	233	Notes Payable to Associated Companies		25,073,594	#DIV/0!
19	234	Accounts Payable to Associated Companies	7,909,460	331,517	-96%
20	235	Customer Deposits	494,179	560,421	13%
21	236	Taxes Accrued	6,415,969	6,201,185	-3%
22	237	Interest Accrued	5,043,269	3,488,455	-31%
23	238	Dividends Declared			
24	239	Matured Long Term Debt			
25	240	Matured Interest			
26	241	Tax Collections Payable	487,615	458,849	-6%
27	242	Miscellaneous Current & Accrued Liabilities	3,737,832	3,558,658	-5%
28	243	Obligations Under Capital Leases - Current			
29	**TOTAL Current & Accrued Liabilities**		30,530,135	46,774,752	-35%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	2,046,869	2,237,737	-9%
34	253	Other Deferred Credits	12,742,428	13,282,677	-4%
35	255	Accumulated Deferred Investment Tax Credits	1,313,259	1,034,144	27%
36	256	Deferred Gains from Disposition Of Util. Plant			
37	257	Unamortized Gain on Reacquired Debt			
38	281-283	Accumulated Deferred Income Taxes	72,030,134	75,078,587	-4%
39	**TOTAL Deferred Credits**		88,132,690	91,633,145	-4%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		506,273,610	468,449,733	8%

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2004

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Intangible Plant**			
3				
4	301 Organization			
5	302 Franchises & Consents			
6	303 Miscellaneous Intangible Plant			
7				
8	**TOTAL Intangible Plant**			
9				
10	**Production Plant**			
11				
12	Steam Production			
13				
14	310 Land & Land Rights			
15	311 Structures & Improvements			
16	312 Boiler Plant Equipment			
17	313 Engines & Engine Driven Generators			
18	314 Turbogenerator Units			
19	315 Accessory Electric Equipment			
20	316 Miscellaneous Power Plant Equipment			
21				
22	**TOTAL Steam Production Plant**			
23				
24	Nuclear Production			
25				
26	320 Land & Land Rights			
27	321 Structures & Improvements			
28	322 Reactor Plant Equipment			
29	323 Turbogenerator Units			
30	324 Accessory Electric Equipment			
31	325 Miscellaneous Power Plant Equipment			
32				
33	**TOTAL Nuclear Production Plant**			
34				
35	Hydraulic Production			
36				
37	330 Land & Land Rights			
38	331 Structures & Improvements			
39	332 Reservoirs, Dams & Waterways			
40	333 Water Wheels, Turbines & Generators			
41	334 Accessory Electric Equipment			
42	335 Miscellaneous Power Plant Equipment			
43	336 Roads, Railroads & Bridges			
44				
45	**TOTAL Hydraulic Production Plant**			

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED) Year: 2004

	Account Number & Title		Last Year	This Year	% Change
1					
2		Production Plant (cont.)			
3					
4	Other Production				
5					
6	340	Land & Land Rights			
7	341	Structures & Improvements			
8	342	Fuel Holders, Producers & Accessories			
9	343	Prime Movers			
10	344	Generators			
11	345	Accessory Electric Equipment			
12	346	Miscellaneous Power Plant Equipment			
13					
14		**TOTAL Other Production Plant**			
15					
16		**TOTAL Production Plant**			
17					
18		**Transmission Plant**			
19					
20	350	Land & Land Rights	20,312		-100%
21	352	Structures & Improvements			
22	353	Station Equipment			
23	354	Towers & Fixtures			
24	355	Poles & Fixtures	246,300		-100%
25	356	Overhead Conductors & Devices	300,275		-100%
26	357	Underground Conduit			
27	358	Underground Conductors & Devices			
28	359	Roads & Trails			
29					
30		**TOTAL Transmission Plant**	566,887		#DIV/0!
31					
32		**Distribution Plant**			
33					
34	360	Land & Land Rights	5,992	26,304	339%
35	361	Structures & Improvements	5,970	5,970	
36	362	Station Equipment	434,705	441,924	2%
37	363	Storage Battery Equipment			
38	364	Poles, Towers & Fixtures	120,717	367,017	204%
39	365	Overhead Conductors & Devices	109,732	410,007	274%
40	366	Underground Conduit	909	909	
41	367	Underground Conductors & Devices	15,834	15,834	
42	368	Line Transformers	42,704	42,704	
43	369	Services	3,367	3,367	
44	370	Meters	6,278	6,278	
45	371	Installations on Customers' Premises			
46	372	Leased Property on Customers' Premises			
47	373	Street Lighting & Signal Systems			
48					
49		**TOTAL Distribution Plant**	746,208	1,320,314	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2004

	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment			
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment			
10	395 Laboratory Equipment			
11	396 Power Operated Equipment			
12	397 Communication Equipment	14,732	14,732	
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	14,732	14,732	
17				
18	**TOTAL Electric Plant in Service**	1,327,827	1,335,046	

MONTANA DEPRECIATION SUMMARY

Year: 2004

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	Accumulated Depreciation This Year Bal.	Current Avg. Rate
1					
2	Steam Production				
3	Nuclear Production				
4	Hydraulic Production				
5	Other Production				
6	Transmission		150,436		
7	Distribution	1,320,314	250,941	360,344	2.78%
8	General	14,732	5,575	6,086	7.18%
9	**TOTAL**	1,335,046	406,952	366,430	9.96%

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	N/A		#VALUE!
3	152 Fuel Stock Expenses Undistributed			-
4	153 Residuals			-
5	154 Plant Materials & Operating Supplies:			-
6	Assigned to Construction (Estimated)			-
7	Assigned to Operations & Maintenance			-
8	Production Plant (Estimated)			-
9	Transmission Plant (Estimated)			-
10	Distribution Plant (Estimated)			-
11	Assigned to Other			-
12	155 Merchandise			-
13	156 Other Materials & Supplies			-
14	157 Nuclear Materials Held for Sale			-
15	163 Stores Expense Undistributed			
16				
17	**TOTAL Materials & Supplies**	-	-	-

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent		% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number	83.4.25			
2	Order Number	4988			
3					
4	Common Equity		52.83%	15.00%	7.92%
5	Preferred Stock		11.96%	9.03%	1.08%
6	Long Term Debt		35.21%	7.75%	2.73%
7	Other				
8	**TOTAL**		100.00%		11.73%
9					
10	Actual at Year End				
11					
12	Common Equity		51.76%		-
13	Preferred Stock				-
14	Long Term Debt		48.24%		-
15	Other				-
16	**TOTAL**		100.00%		-

STATEMENT OF CASH FLOWS

Year: 2004

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	25,994,983	19,208,760	35%
6	Depreciation	18,847,762	18,721,971	1%
7	Amortization	355,903	363,032	-2%
8	Deferred Income Taxes - Net	8,538,517	5,388,321	58%
9	Investment Tax Credit Adjustments - Net	(318,304)	(279,115)	-14%
10	Change in Operating Receivables - Net	521,267	(1,489,003)	135%
11	Change in Materials, Supplies & Inventories - Net	181,780	(1,952,729)	109%
12	Change in Operating Payables & Accrued Liabilities - Net	(2,283,377)	(8,828,977)	74%
13	Allowance for Funds Used During Construction (AFUDC)	(44,249)	(94,433)	53%
14	Change in Other Assets & Liabilities - Net	(5,446,732)	1,847,561	-395%
15	Other Operating Activities (explained on attached page)	(1,905,700)		#DIV/0!
16	**Net Cash Provided by/(Used in) Operating Activities**	44,441,850	32,885,388	35%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(25,382,896)	(13,684,203)	-85%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets			
23	Investments In and Advances to Affiliates	14,798,261	37,709,836	-61%
24	Contributions and Advances from Affiliates			
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	(500,432)	(213,546)	-134%
27	**Net Cash Provided by/(Used in) Investing Activities**	(11,085,067)	23,812,087	-147%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt		18,650,000	-100%
32	Preferred Stock			
33	Common Stock			
34	Other:			
35	Net Increase in Short-Term Debt			
36	Other:		25,073,594	-100%
37	Payment for Retirement of:			
38	Long-Term Debt	(3,095,360)	(71,486,080)	96%
39	Preferred Stock			
40	Common Stock			
41	Other:		(5,508,745)	100%
42	Net Decrease in Short-Term Debt			
43	Dividends on Preferred Stock			
44	Dividends on Common Stock	(29,727,692)	(24,000,000)	-24%
45	Other Financing Activities (explained on attached page)			
46	**Net Cash Provided by (Used in) Financing Activities**	(32,823,052)	(57,271,231)	43%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	533,731	(573,756)	193%
49	**Cash and Cash Equivalents at Beginning of Year**	517,848	1,051,579	-51%
50	**Cash and Cash Equivalents at End of Year**	1,051,579	477,823	120%

LONG TERM DEBT

Year: 2004

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1	Series								
2									
3	Y	Jun-88	Jun-18	6,000,000	5,906,578	3,970,000	9.64%	392,168	9.88%
4	Z	May-91	May-21	35,000,000	34,790,305	28,305,000	9.41%	2,718,030	9.60%
5									
6	AB	Sep-94	Sep-24	45,000,000	44,243,911	-	8.44%	3,029,721	
7	AC	Feb-95	Feb-10	30,000,000	29,766,300	30,000,000	8.12%	2,418,000	8.06%
8	AE	Aug-02	Aug-32	75,000,000	74,008,936	75,000,000	7.23%	5,455,881	7.27%
9									
10									
11	1992 Pollution Control								
12	Revenue Bonds:								
13	Lawrence County SD	Jun-92	Jun-10	5,850,000	5,753,590	-	6.81%	264,785	
14	Pennington County SD	Jun-92	Jun-10	2,050,000	1,969,993	-	6.97%	135,640	
15	Campbell County WY	Jun-92	Jun-10	1,550,000	1,473,355	-	7.05%	102,651	
16	Weston County WY	Jun-92	Jun-10	2,850,000	2,770,414	-	6.89%	185,729	
17									
18	2004 Pollution Control								
19	Revenue Bonds:								
20	Campbell County WY	Nov-04	Oct-14	1,550,000	1,517,018	1,550,000	4.80%	7,593	0.49%
21	Campbell County WY	Nov-04	Oct-14	12,200,000	11,964,016	12,200,000	5.35%	66,613	0.55%
22	Pennington County SD	Nov-04	Oct-14	2,050,000	1,999,347	2,050,000	4.80%	10,042	0.49%
23	Weston County WY	Nov-04	Oct-14	2,850,000	2,791,873	2,850,000	4.80%	13,962	0.49%
24									
25	1994A Environ Improv B.	Jun-94	Jun-24	3,000,000	2,930,057	2,855,000	4.35%	87,855	3.08%
26									
27	1994 Gillette Refund Bond	Jul-94	Jun-24	12,200,000	11,888,427	-	7.70%	879,000	
28									
29	Bear Paw Energy Note Payable	Jun-00	May-12	1,078,000	1,078,000	425,648	13.70%	60,659	14.25%
30									
31									
32	**TOTAL**			238,228,000	234,852,120	159,205,648		15,828,329	9.94%

PREFERRED STOCK

Year: 2004

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1	NONE									
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

COMMON STOCK

Year: 2004

		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
1	100% of common stock privately held by								
2	the Parent Company								
3	Black Hills Corp.								
4	January	23,416,396							
5									
6	February	23,416,396							
7									
8	March	23,416,396							
9									
10	April	23,416,396							
11									
12	May	23,416,396							
13									
14	June	23,416,396							
15									
16	July	23,416,396							
17									
18	August	23,416,396							
19									
20	September	23,416,396							
21									
22	October	23,416,396							
23									
24	November	23,416,396							
25									
26	December	23,416,396							
27									
28									
29									
30									
31									
32	TOTAL Year End								

MONTANA EARNED RATE OF RETURN

Year: 2004

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service			
3	108 (Less) Accumulated Depreciation			
4	**NET Plant in Service**			
5				
6	Additions			
7	154, 156 Materials & Supplies			
8	165 Prepayments			
9	Other Additions			
10	**TOTAL Additions**			
11				
12	Deductions			
13	190 Accumulated Deferred Income Taxes			
14	252 Customer Advances for Construction			
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions			
17	**TOTAL Deductions**			
18	**TOTAL Rate Base**			
19				
20	**Net Earnings**			
21				
22	**Rate of Return on Average Rate Base**			
23				
24	**Rate of Return on Average Equity**			
25				
26	Major Normalizing Adjustments & Commission			
27	Ratemaking adjustments to Utility Operations			
28				
29	NOTE: This schedule is not completed because			
30	Montana revenues represent less than 1%			
31	of the Company's revenues.			
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	**Adjusted Rate of Return on Average Rate Base**			
48				
49	**Adjusted Rate of Return on Average Equity**			

MONTANA COMPOSITE STATISTICS

Year: 2004

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	1,335
5	107	Construction Work in Progress	
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(366)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	969
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	779
18			
19	403 - 407	Depreciation & Amortization Expenses	
20		Federal & State Income Taxes	
21		Other Taxes	
22		Other Operating Expenses	
23		TOTAL Operating Expenses	
24			
25		Net Operating Income	779
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	779
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	13
36		Commercial	19
37		Industrial	2
38		Other	
39			
40		**TOTAL NUMBER OF CUSTOMERS**	34
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	6,052
45		Average Annual Residential Cost per (Kwh) (Cents) *	7.55
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	35
48		Gross Plant per Customer	39,266

MONTANA CUSTOMER INFORMATION

Year: 2004

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Carter and Powder River Counties					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**					

MONTANA EMPLOYEE COUNTS

Year: 2004

	Department	Year Beginning	Year End	Average
1	N/A			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**			

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2005

	Project Description	Total Company	Total Montana
1	N/A		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**		

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2004

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	5	1800	343	264,947	79,805
2	Feb.	11	1900	329	226,161	53,354
3	Mar.	2	900	290	239,997	69,176
4	Apr.	29	1000	265	229,358	77,569
5	May	5	1400	267	230,302	69,566
6	Jun.	30	1300	317	275,664	112,451
7	Jul.	19	1500	376	302,594	114,514
8	Aug.	2	1600	373	308,370	128,649
9	Sep.	1	1500	344	253,658	92,174
10	Oct.	25	1200	267	250,041	84,163
11	Nov.	29	1900	306	256,820	88,227
12	Dec.	23	1800	332	303,942	120,939
13	**TOTAL**				3,141,854	1,090,587

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.					
15	Feb.	*Peak information maintained on a total system basis only.				
16	Mar.					
17	Apr.					
18	May					
19	Jun.					
20	Jul.					
21	Aug.					
22	Sep.					
23	Oct.					
24	Nov.					
25	Dec.					
26	**TOTAL**					

TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,752,620	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	1,509,635
4	Hydro - Conventional			
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	27,825	for Resale	450,334
7	(Less) Energy for Pumping			
8	**NET Generation**	1,780,445	Non-Requirements Sales	
9	Purchases	1,370,825	for Resale	1,090,587
10	Power Exchanges			
11	Received	17,740	Energy Furnished	
12	Delivered	(35,695)	Without Charge	
13	**NET Exchanges**	(17,955)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received	2,175,847	Electric Utility	7,702
16	Delivered	(2,167,308)		
17	**NET Transmission Wheeling**	8,539	Total Energy Losses	83,596
18	Transmission by Others Losses			
19	**TOTAL**	3,141,854	**TOTAL**	3,141,854

SOURCES OF ELECTRIC SUPPLY

Year: 2004

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1	Thermal	Ben French	Rapid City, SD	98	3,058
2					
3	Thermal	Ben French	Rapid City, SD	10	1,039
4					
5	Thermal	Ben French	Rapid City, SD	24	144,283
6					
7	Thermal	Osage	Osage, WY	35	232,978
8					
9	Thermal	Wyodak	Gillette, WY	69	534,877
10					
11	Thermal	Neil Simpson Complex	Gillette, WY	112	840,481
12					
13	Thermal	Neil Simpson Complex	Gillette, WY	39	7,025
14					
15	Thermal	Lange	Rapid City, SD	39	16,703
16					
17	Purchases	See Schedule 33			1,052,708
18					
19	Wheeling	See Schedule 33			14,254
20					
21	Total Interchange	See Schedule 33			(18,885)
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			426	2,828,521

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2004

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1	N/A						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	**TOTAL**						

MONTANA CONSUMPTION AND REVENUES

Year: 2004

	Sales of Electricity	Operating Revenues		MegaWatt Hours Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$ 5,484	$ 5,020	73	68	13	12
2	Commercial - Small	13,972	16,681	145	170	19	20
3	Commercial - Large	758,705	637,833	16,470	14,031	2	2
4	Industrial - Small						
5	Industrial - Large						
6	Interruptible Industrial						
7	Public Street & Highway Lighting						
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities						
11	Interdepartmental						
12							
13	**TOTAL**	$ 778,161	$ 659,534	16,688	14,269	34	34